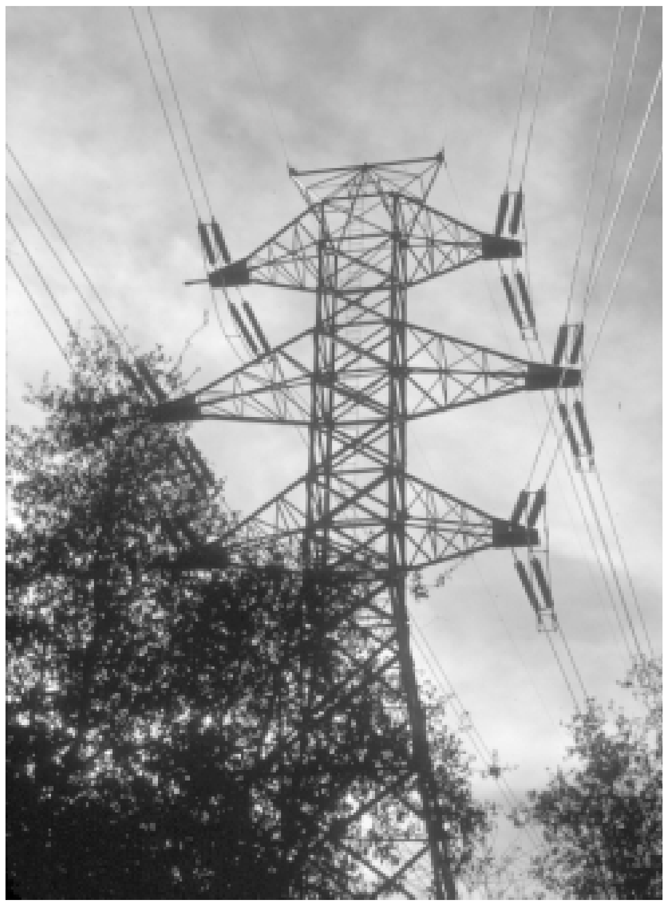
CALIFORNIA ENERGY COMMISSION

SB 735

THE ROLE OF ENERGY EFFICIENCY AND DISTRIBUTED GENERATION IN GRID PLANNING

Report to the Governor and Legislature



APRIL 2000
P300-00-003

Gray Davis, *Governor*

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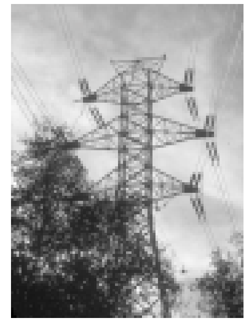

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Executive Summary

Introduction

As directed in SB 735, the Energy Commission has investigated whether and how energy efficiency and privately-owned distributed generation could provide comparably reliable alternatives to transmission system or generation projects in the Independent System Operator s electric grid planning process. The legislation required the Energy Commission to submit this report to the Governor and the Legislature no later than May˚1, 2000.

The Legislature perceived that although the new market was developing transmission planning and new generation, the potential contributions of energy efficiency and distributed generation to the transmission grid s reliability were not well understood. To date, the Independent System Operator has not used energy efficiency or privately-owned distributed generation in the grid planning process.

Unlike transmission and generation that are built to produce and move bulk power, customers acquire energy efficient equipment and distributed generation to reduce their individual energy consumption and reliance on the grid. These consumer investments can reduce the need for grid-delivered electricity, which can in turn reduce the need for transmission expansion or potentially solve local system performance problems. But these investments usually happen independently and without regard to their impact on the transmission system. The question for this report is whether and how the Independent System Operator should account for or encourage useful energy efficiency or distributed generation investments to improve the reliability of the transmission grid.

In planning for expansion or improvements to the grid, the Independent System Operator s primary goal is to maintain or enhance reliability. Reliability has a specialized meaning for transmission; to be reliable a transmission grid must have both adequacy and security. A system is adequate when sufficient generation and transmission resources are available to meet projected needs at all times. It is secure when it can remain intact even after planned and unplanned outages or other equipment failures occur.

Structure of this Report

The report first investigates whether energy efficiency or privately-owned distributed generation are technically feasible methods to enhance the transmission system s adequacy or security. It then investigates potential impacts on California s electricity market design of various methods to incorporate investments in energy efficiency or distributed generation into planning for expansion of the transmission grid. Four options which the Independent System Operator might pursue are examined, followed by recommendations on actions the

Independent System Operator and State agencies might take regarding the role of energy efficiency and distributed generation in grid planning.

Findings on Energy Efficiency Feasibility

Peak load growth could be reduced through efficiency investments, which would reduce the total amount of transmission that needs to be built. Transmission is built to serve load at the time of highest demand. In California, peak demand occurs on hot summer afternoons and is driven by commercial and residential air conditioning and lighting. The efficiency of these end-uses can be improved in both new buildings and replacement situations.

Encouraging energy efficiency investments is a technically feasible method to ensure a sufficient supply of electricity is available. It is much less feasible as a means to obtain system security but may, in case-by-case situations, reduce possible over heating and voltage problems on transmission lines.

A number of market barriers exist to enlisting either private or public energy efficiency in grid planning at this time. Energy efficiency investments are made at the customers site for customers purposes, are generally so small that they would need to be aggregated to make a sizeable impact at the transmission level, are permanent and are not under the control of the transmission operators.

For private investments, the Independent System Operator would need to foster participation by a sector that has no existing business relationships with the transmission system. Performance terms and operating conditions would need to be developed so that the ISO and transmission owners would be secure that load reductions will occur when they are needed and the customer-owners would be secure that the costs of participation do not swamp the value of the incentive they are being offered.

The State could play a role in fostering the use of energy efficiency to reduce pressure on key transmission sectors. The State could assist the Independent System Operator and transmission owners in accounting for trends in future energy efficiency from programs and rate design by using its staff expertise to participate in development of the load forecasts. Its chief programmatic tool is the energy efficiency funded through the Public Goods Charge, which could be refocused to target reducing peak demand or improving system security for end-users in transmission-deficient areas. The State could also use Public Goods Charge money and staff expertise to foster third-party participation through program pilots, marketing and customer outreach.

Findings on Distributed Generation Feasibility

Distributed generation investments are currently less technically feasible than energy efficiency programs as a transmission alternative. Several barriers limit the effectiveness of distributed generation to compete effectively to displace a local or regional transmission project. Some of these barriers are technology maturity, cost, siting and permitting, interconnection, and institutional issues.

Many of these barriers are in the process of being removed through product development and regulatory proceedings that the Public Utilities Commission and the Energy Commission are conducting this year. Distributed generation may become a feasible option within the next few years, but further work is needed on the market mechanics of how distributed generation would be contracted for and held accountable by the owners and operators of the transmission system.

Distributed generation can provide system benefits for certain transmission projects but for many projects, it is probably not capable of providing equal reliability benefits per dollar of investment in a transmission upgrade. A superior long-term strategy would be to pursue both transmission upgrades and distributed generation investments as a package to improve reliability and reduce costs.

Findings on the Importance of New Rate Design

The technical and market feasibility of both energy efficiency and distributed generation are going to change in the next few years as new rate designs go into effect for customers who take full service from their utility. Rates may have an increased fixed component, or they may vary dramatically from month to month. There could be charges that make it more reducing peak demand more cost-effective than reducing overall energy use.

As the California Public Utilities Commission completes its rate design proceedings, these new designs will provide incentives or disincentives for end-users to invest in energy efficiency or distributed generation. Once the rate freeze is concluded, CPUC new rate design decisions will have significant influences on expected load growth, which should be taken into account in transmission planning. And those customers who choose a separate power supplier may receive different kinds of incentives or disincentives.

As the Independent System Operator considers whether to make a role for energy efficiency or distributed generation in grid planning, they will need to assess the overall market price signals to see if a supplemental signal is of value.

Recommendations on Options for Grid Planning

The Commission evaluated four options that the Independent System Operator might use to incorporate energy efficiency programs or privately-owned distributed generation into grid planning.

Option 1 focuses on how energy efficiency programs or privately-owned distributed generation are accounted for in grid planning. Options 2 through 4 present incentives for encouraging energy efficiency and distributed generation as alternatives to transmission upgrades. Encouraging the funding of specific projects as part of the grid planning process presents significant implementation challenges. The problems arise because in California s market structure, energy efficiency and distributed generation would not be owned by the owner of transmission.

The alternative projects would have to be acquired under contract and the transmission owner would require compensation for foregone earnings from the displaced transmission upgrade. Designing contracts and cost-recovery rules among the system operator, transmission owners and owners of energy efficiency or distributed generation is likely to be difficult. The projects would have to serve both the customer-owner and the transmission system.

Because of these market design and contractual difficulties, the procurement options that target energy efficiency programs to defer or displace transmission projects cannot be achieved unless a funding source and an active sponsor is identified. If the source is the Public Goods Charge, this action would change the historic practice of distributing energy efficiency program benefits broadly among all those funding the program and dilute the current emphasis on market transformation. Such changes in the role of the Public Goods Charge funds should not be made without specific legislative direction

Option 1: Future Impacts in Load Forecasts

The first option is to include the impacts of future energy efficiency and distributed generation within the load forecasts used for transmission planning. This option will result in improved planning efficiency for transmission upgrades, because it will assure the amount of transmission required is not overestimated. The staff recommends that the State pursue Option 1 today because it is feasible, provides a more accurate basis for planning transmission upgrades, and lessens the risk to California consumers who could otherwise be paying for transmission upgrades that are not necessary.

Transmission owners, utility distribution companies, the Independent System Operator and the Energy Commission should work collaboratively to forecast changes in systemwide and local load patterns that would influence transmission planning results. A stakeholder process should develop explicit criteria for developing improved transmission planning area load forecasts. The state role in assisting this process could be limited to advice on which criteria are important or it could be expanded to participating directly in the load forecasting process in the areas of key future assumptions, and estimates of impacts of energy efficiency programs, distributed generation deployment, and rate design.

Option 2: Sponsored Energy Efficiency/Distributed Generation Projects in Transmission Owner Plans

This option would require sponsored investments in energy efficiency and distributed generation to be evaluated at the transmission owner level as options to defer or displace upgrades to the transmission system.

When a transmission owner is examining options to address a local load growth or system security problem, it has dozens of different combinations of equipment that could work. At this level it is much more realistic to consider a smaller, local alternative such as energy efficiency or distributed generation. Energy efficiency or distributed generation could be included as a component of a larger group of projects which, taken as a whole, resolve the problem.

Although the Independent System Operator and transmission owners have been open to a third-party sponsor bringing an energy efficiency or distributed generation project to the table, there are no incentives and plenty of risk in such a third-party proposal.

We recommend that the Independent System Operator and transmission owners consider testing this option in a focused demonstration. The Independent System Operator or its designee would need to commit resources to run the demonstration, market the opportunity to potential developers, work with parties to design model Request for Proposals and contracts, and test the feasibility of a program design. If the legislature were to authorize it, state regulatory agencies could participate with the Independent System Operator to oversee this project and could provide partial funding.

Option 3: Energy Efficiency Investments

In option 3 transmission assessments would be extended to create a five- to ten-year forecast that would identify emerging peak demand problems and focus investments in energy efficiency or distributed generation there. The State would direct a portion of Public Goods Charge investments to reduce peak demand in specific areas.

This option benefits from using the known features of successful energy efficiency programs. EE programs would not have to be cobbled together quickly to compete against the specific attributes of an identified transmission project. Further, public EE investments would be located in areas where the system benefits accrue to all ratepayers. The mid-term assessment could also provide an early alert system to transmission planners on how rate design is changing the market fundamentals of peak demand. Building a transmission system based on an historic peak load profile and very hot weather is going to become increasingly risky if demand responsiveness takes off and consumers alter their purchasing behavior.

This option does not address distributed generation, because there is no public program directing where distributed generation shall be built. However, the implications of future distributed generation development could be fed into the five- to ten-year outlook.

This option would require cooperation among State agencies, the Independent System Operator, transmission owners and market participants. The Independent System Operator and transmission owners would need to produce longer-term forecasts than they now do. The Energy Commission would need to participate with the load forecasting process. The Public Utilities Commission would need to approve targeting of programs and should consider whether increased program flexibility or multi-year funding would be beneficial.

Option 4: Alternatives to Identified Transmission Projects

Option 4 provides a competitive solicitation at the Independent System Operator level in which alternatives could compete to provide reliability benefits equivalent to the expected benefits of proposed transmission projects.

The ability of energy efficiency programs and privately-owned distributed generation to compete on economic terms with identified transmission projects is doubtful at the current time. Some of the implementation problems with this option are as follows:

- Energy efficiency measures are necessarily diffuse and involve numerous participants. Packaging measures into a program could provide the appropriate scale, but this could hardly be accomplished in an eight week bidding timeframe.

- Distributed generation is operated on a schedule that maximizes the economic benefits to the project sponsor — usually the occupant of a commercial or industrial premise. An operating schedule that provides equivalent needs to a transmission project may disrupt the schedule most beneficial to the premise occupant. Because energy costs are typically a small portion of most businesses total cost and the costs of disrupted service are high, most firms are not likely to tolerate disruptions in their schedules.

- Additional costs for metering and telemetry requirements, imposed by the Independent System Operator to ensure that the distributed generation facility was operating according to the schedule, might make the project uneconomic

These considerations make energy efficiency and distributed generation unlikely to be successful in displacing transmission projects once the transmission has been identified and specific needs characterized. At this time, we find it unlikely that energy efficiency or distributed generation could be successful in a competitive solicitation. However, should the Independent System Operator implement a competitive solicitation, the solicitation should be designed to include energy efficiency and distributed generation options. In a local situation, they might be a cost-effective choice and the contractual issues should be no more difficult than those for a generator.

Conclusion

Although it has proven difficult to design a method for energy efficiency and distributed generation to participate directly in grid planning, these alternative investments can contribute to system adequacy and grid reliability. The difficulties arise in designing focused EE or DG investments to defer or displace specific transmission projects. Over the years, the Energy Commission has faced a similar problem in how to compare energy efficiency to proposed power plants. As the Warren-Alquist Act codified, it is unreasonable to expect that a group of programs could be suddenly designed and sponsored to replace a power plant. Similarly for transmission, the principal role of energy efficiency and privately-owned distributed generation appears to be reducing total load growth before transmission options are evaluated.

Section I. Reporting Requirements and Planning Context

Introduction

This section discusses the reporting requirements spelled out in Senate Bill 735 and the context for grid planning. When SB 735 was enacted in October 1999, its purpose was to examine how energy efficiency and distribution generation would fit into what appeared to be a well-defined grid planning process. But the grid planning process has continued to change since then, so the Energy Commission had to broaden its assessment. Rather than examining an established process, the report looks at more basic questions concerning the relationship among energy efficiency, distribution generation and transmission planning. The statute requires that the Commission provide a report to the Governor and the Legislature no later than May 1, 2000, as described below.

Reporting Requirements

SB 735 (Statutes. 1999, Chapter. 1021) SEC. 3. The scope of the Supplemental Report required in Item 3360-001-0465 shall be as follows:

(a) The Energy Resources, Conservation and Development Commission shall investigate the suitability, technical feasibility, behavioral efficacy, policy and implementation issues, and cost and benefits of methods by which private or public conservation and energy efficiency projects or private distributed generation projects could provide comparably reliable alternatives to transmission system or generation projects in the Independent System Operator's electric grid planning process.

Although there is not an extensive legislative history to guide this study, our understanding of the intent is that the Legislature believed that transmission planning and generation development were reasonably well in hand, but they perceived a lack of equal review of the potential role of energy efficiency and distributed generation as contributors to system reliability.

The issued addressed in the report had to be broadened as events unfolded over the winter.

Usually, energy efficiency and distributed generation are evaluated based on the values which they offer to the consumer-purchasers. In this case, the report examines another attribute — how they compare to transmission or generation in providing comparable reliability to the integrated grid.

Planning Context and Reliability Criteria

The ISO is responsible for planning a portion of the western inter-connected grid. The ISO s need to establish and maintain a reliable transmission system is embedded in its enabling statute, which specifies:

> the Independent System Operator shall ensure efficient use and reliable operation of the transmission grid. [It] shall seek [of FERC] the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Westerns Systems Coordinating Council. [Sections 345 and 346, AB 1890]

In addition to this charge, the Federal Energy Regulatory Commission has directed that it expects potential regional transmission organizations to take a proactive grid planning role. These two directives set the stage for the ISO s role in grid planning[1].

The Independent System Operator (ISO) submitted a proposed grid planning process to the Federal Energy Regulatory Commission (FERC) on December 22, 1999. Because of FERC concerns on related market design issues and the concerns of stakeholders, the ISO withdrew its grid planning proposal in February, 2000 and proposed a streamlined effort to stakeholders in early March 2000. That initiative is still under consideration.

A reliable grid provides multiple, alternative connections between generating plants, substations and load centers, as well as multiple interconnections with other control areas, utilities and regions. The power flows must be under continuous central coordination in order for the system to stay balanced. Planners take this into account using two standard reliability components: adequacy and security.

- Adequacy implies that there are sufficient generation and transmission resources available to meet projected needs at all times, including peak conditions, plus reserves for contingencies.

- Security implies that the system will remain intact even after planned and unplanned outages or other equipment failures occur. (Department of Energy, Electricity Reliability Task Force Interim Report, July 24, 1997)

Specific transmission projects may serve adequacy, security, or some combination of the two. Adequacy transmission projects increase the overall capacity to import power into a broad region of California. For these transmission projects, overall load within the region is the driver for the expanding import capacity or regional generation. As will be discussed later, some grid planning stakeholders took strong exception to using generation, energy efficiency or distributed generation as alternatives to transmission to meet adequacy needs.

The concept of system security refers to the ability to move power without interruption from power supply to the end user. California could have abundant generation and transmission, but still have an unreliable system if the physical characteristics of electricity were not also managed and balanced. To prevent sudden disturbances, the transmission system must operate and react on a near instantaneous basis to maintain appropriate thermal, voltage, and frequency parameters. This means that systems must be designed with sufficient transmission line redundancy to prevent thermal overloading from the sudden loss of one or more lines, have appropriately placed generators and capacitors to provide immediate voltage support in case a critical generator becomes inoperable, and the equipment to regulate and maintain transmission line harmonics within specific tolerances.

These security characteristics have traditionally been managed through the configuration of transmission. Most electricity users are never aware of system security; it is the largely invisible features of the system which allow power to flow instantaneously and unceasingly even if there is a problem. Energy efficiency projects and distributed generation have been built assuming that system security will be provided; they have not been built specifically to provide elements of system security. In the new restructured electricity environment, on a case-by-case basis, they might do so.

Energy efficiency and distributed generation projects may displace transmission projects to some extent and under certain conditions. Energy efficiency and distributed generation are being evaluated for comparison against many different types, size and purposes of transmission investment. These constraints mean that evaluation of an energy efficiency/distributed generation project has to be site-specific so that the characteristics of the project in connection with all other local supply, load and transmission can be assessed.

Section II: Suitability of Alternatives

This section discusses the suitability of energy efficiency programs and distributed generation investments to displace transmission projects. In addition, it includes an analysis of market structure issues, which is necessary if the technical feasibility and cost-effectiveness of energy efficiency programs and privately funded distributed generation are to be understood.

Energy Efficiency

California has a 20-year history of encouraging energy efficiency investments through rate design, building and appliance standards, and utility-sponsored demand-side management and load management programs (see definitions in **Table 1).** The peak demand impacts of these programs, and our forecasts of future impacts, are shown in **Figure 1**. For example, utility programs shaved 3,000 MW off of what peak demand would have been in 1998. The total peak contribution of programs, standards and private investments was a reduction of 6,500 MW, a savings of 12 percent of projected 1998 load.

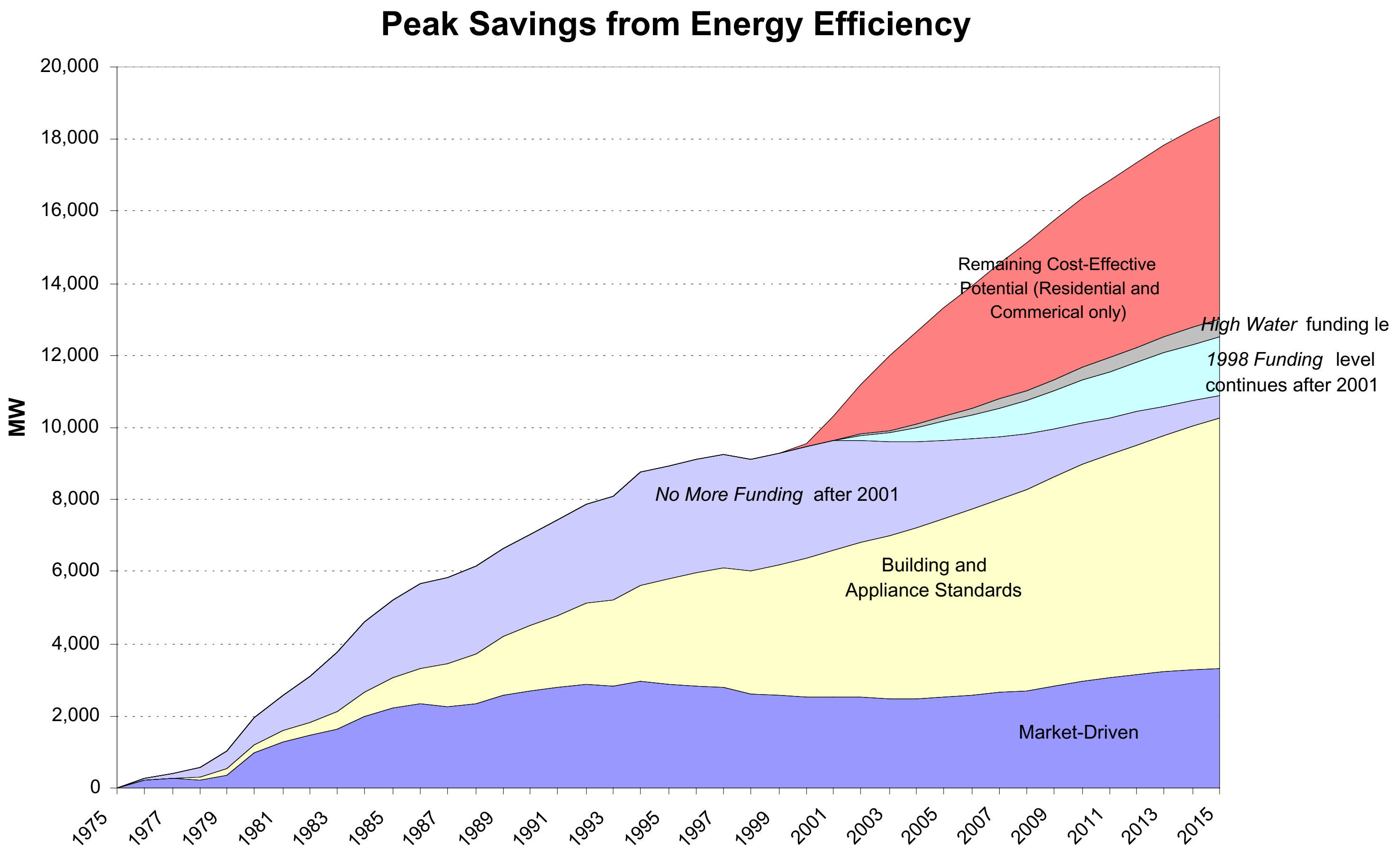
Table 1
Definitions

- Energy efficiency - actions that reduce overall consumption during most hours of operation of the equipment or building affected by the measure, typically without affecting the services provided.
- Demand responsiveness - the ability of customers to respond to prices on a near-term basis.
- Demand-side management - utility activities designed to encourage consumers to modify patterns of electricity use, including the level of peak demand.
- Load management - actions to reduce electric peak demand or shift electric demand from the hours of peak demand to off-peak time periods.

Most energy efficiency programs impact transmission adequacy by reducing the electrical load; only rarely have energy efficiency programs been used to defer transmission security investments.

Given this long history of investment, it is reasonable to question whether additional energy efficiency investments are cost-effective to pursue. As **Figure 1** shows, even if future funding for utility programs were increased to its historic high, only two-thirds of potential cost-effective efficiency investments would be tapped by either the public or private sector.

Figure 1

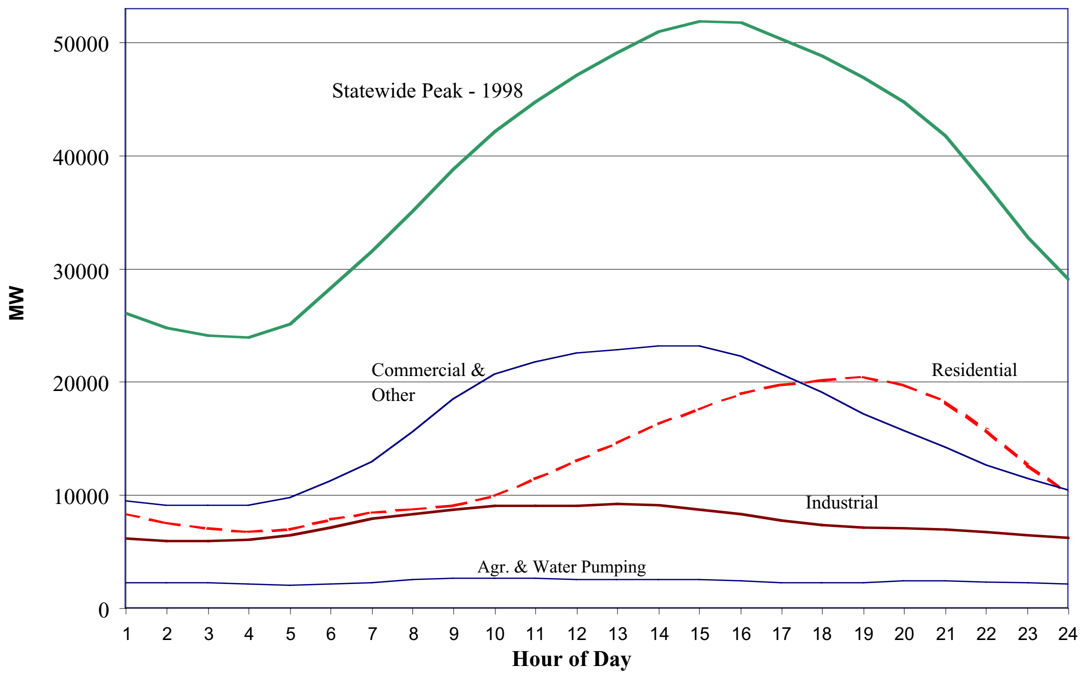


Source: Energy Commission (see Appendix A)

Technical Feasibility and Implementation Issues

To examine whether energy efficiency could defer or displace transmission upgrades or additions, we need to determine which sectors are using electricity at the time of system peak and whether the specific equipment in use can be fixed or replaced to improve its efficiency. As **Figure 2** shows, California s commercial sector contributes most to the system peak. Residential use is rapidly rising during this period and so it is also an attractive target for energy efficiency investments that reduce peak demand. The industrial, agriculture and water pumping sectors are relatively constant throughout the day.

Figure 2
Statewide Hourly Peak Demand by Sector
(MW)



The commercial and residential sectors can be further disaggregated into specific end-uses. Commercial air conditioning is the single biggest source of peak demand, followed closely by residential air conditioning, assembly industries, and commercial lighting, which creates internal heat and increases air conditioning load (see **Figure 3**). California s experience has shown that air conditioning and lighting are effective improvement targets in both new and replacement situations. This suggests that there are additional targets of opportunity to reduce peak load through efficiency investments.

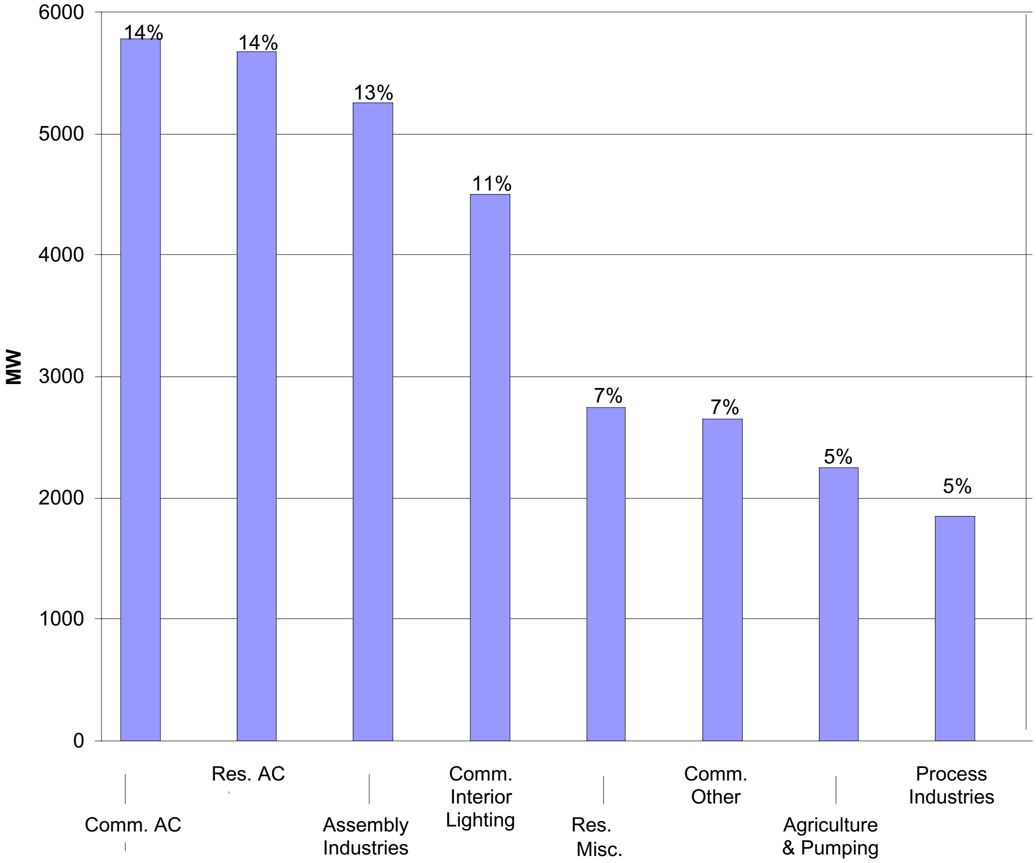
Possible ways to include energy efficiency in the grid planning process include private market response to offers by the ISO, utility, or energy service provider, and publicly funded energy efficiency programs. Load curtailment programs, such as those proposed by PG&E and Southern California Edison for the summer of 2000, are most attractive to larger customers, given current communication and load control capabilities. Building standard improvements, directed toward reducing the overall peak electricity needs in new construction, can reduce the growth in peak loads. Therefore, public and private energy efficiency investments by customers are technically feasible to improve the overall supply adequacy of the transmission grid.

Figure 3

Major Components of Peak Demand (IOUs) (MW)

l Residential and Commercial End Uses

l Industrial Subsectors



Estimating the cost-effectiveness of energy efficiency programs as an alternative to transmission upgrades is problematic because of the technical and administrative costs to assure the ISO and scheduling coordinators that peak load reductions are real. The technical costs would include increased metering and telemetry. The administrative costs have not been identified.

The problem comes not in whether energy efficiency is generically feasible and economic, but in whether we can design focused energy efficiency investments to defer or displace a specific transmission project. As will be discussed in Section IV, the energy efficiency market is not currently designed to respond quickly to put together projects which would meet the ISO s needs. The problem is like that faced by the Energy Commission over the years in how to compare energy efficiency to proposed power plants. Intervenors in siting cases often want to know if energy efficiency could displace the proposed project. As the Warren-Alquist Act codified, it is unreasonable to expect that a group of programs could be suddenly designed and sponsored to replace a power plant. Similarly for transmission, it appears to us that the principal role of energy efficiency is to reduce total load growth before transmission options are evaluated.

Even if future energy efficiency investments reduce load and load growth, if they are not included in load forecasts, grid planners will be unable to take the load reductions associated with current or future energy efficiency impacts into account. Participating Transmission Owners (PTO) load forecasts are calibrated to historic data, so the load impacts of existing energy efficiency investments are embedded. To the extent that market-driven trends of the future are the same as the recent past, then that portion of energy efficiency would also be included. But, based on a review of the load forecasting techniques used in the 1999 ISO Grid Assessment process, it appears that PTOs are not adjusting their load forecasts for the impacts of new construction standards and future energy efficiency programs funded by the Public Goods Charge.

Regulatory Activities Which May Affect Grid Planning

AB 1890 continued funding for utility-sponsored efficiency programs by establishing a Public Goods Charge (PGC) for programs that enhance system reliability and provide in-state benefits, including cost-effective energy efficiency and conservation activities. Over the four-year transition period, the CPUC is overseeing about $250 million per year of energy efficiency PGC funds through utility-administered public programs. The combined impacts of previous contractual commitments and the 1999 program activity are expected to reduce energy usage by an incremental 937 gigawatt hours (GWh) per year on an annual statewide basis, which amounts to an annual incremental reduction of 192˚MW at the time of system peak demand[2]. In 2000, PGC expenditures will save about 575˚MW, and in 2001, the accumulated impact will increase to about 760˚MW.

This year, the Legislature will determine whether and at what level the Public Goods Charge should be extended. Based on the Energy Commission s analysis conducted for the Energy Efficiency Public Goods Charge Report, the continued funding for energy efficiency-oriented programs between 2002 and 2005 could reduce peak demand by an additional 660 MW by 2006. **Figure 1** indicates the annual peak demand impacts that the Energy Commission estimates would result from three different scenarios of spending. **Appendix A** provides documentation for these findings.

The Energy Commission projections of future PGC program impacts assume no change to the current mix of program designs. Shifting funding within current program categories could increase peak benefits for a given funding level. For example, statewide budgets planned by the utilities for 2000 for programs targeted to residential heating and cooling energy use, a major contributor to summer peak, are less than 5 percent of total program spending. If peak demand reductions were made a policy objective of energy efficiency PGC programs, program administrators could likely find many opportunities to reallocate budgets and refocus programs to achieve increased peak demand savings.

Could specifically designed publicly-funded energy efficiency programs also defer or displace transmission or distribution system upgrades? Pursuing a more vigorous evaluation of peak demand impacts and a policy decision to achieve greater peak demand reductions would require changes in current planning and evaluation practices. The utilities administer the PGC programs to achieve CPUC-defined policy objectives that emphasize transforming markets to eliminate barriers to energy efficiency and ultimately privatizing the provision of cost-effective energy-efficient products and services. Because reliability is not one of the current policy objectives, current programs are not designed with peak impacts in mind and impacts are generally not reported. According to recent indications from the President of the CPUC, a shift towards emphasis on peak reduction objectives is likely. If the CPUC modified its policy rules, utilities could modify programs and budgets as early as 2001.

In addition to modifying the programs focus, the measurement of impacts would have to be strengthened. Current measurement and verification would be inadequate to project accurately the peak impacts in a specific transmission area. Insufficient measurement is a problem because planners unused to working with energy efficiency programs may be uncomfortable relying on a distributed negawatt resource. They would like assurances that energy efficiency is real, measurable, permanent, enforceable, and permanent. As has been demonstrated in the CPUC rate-cases, a high enough level of assurance can be obtained to validate payments of millions of dollars or returns to shareholders.

Another policy change would be needed if PGC programs were to provide reliability comparable to that provided by transmission. Transmission projects address local, site-specific concerns. Most PGC programs are implemented on a statewide or utility service area basis; targeting program delivery to local transmission areas might increase program delivery costs. Currently, a few localized programs provide energy efficiency services to targeted market segments in a specific geographic region or to communities. Dedicating some program funds to mitigating peak demand in specific areas would involve a change in budget priorities across program categories and that would raise questions of fairness.

Historically, energy efficiency funding has used a criterion of servicewide beneficiaries, rather than targeting the funds to specific locales. The rationale is that energy efficiency programs should return benefits to all classes of customers in proportion to their payments into the energy efficiency fund. Spending a disproportionate share of overall customer contributions in a subset of a utility s service area would run contrary to that policy. This policy does not fit in with the more general grid planning procedures of the ISO. Much of the grid planning is at a fairly localized level; many of the deficiencies that will affect the reliability of the ISO grid are localized. Local investment may produce local benefits, but the overall impact is to provide reliability benefits for the grid. If non-wires projects were to substitute at a lower cost for a wires project to solve these same criteria violations on a comparable basis, then the result should be a more cost-effective solution to the problem.

Opportunities to use market-based energy efficiency to defer specific commitments are likely to be limited. Given the large number of participants that would need to be aggregated to achieve significant load reductions and the telemetry and accountability requirements likely to be required by the ISO, only large customers in unique areas would be able to put together a suitable project.

Conclusions Regarding Energy Efficiency

Comparing energy efficiency to transmission s reliability attributes, energy efficiency investments are technically feasible methods for supply adequacy purposes, but they are much less feasible as a means to obtain system security. Energy efficiency investments are made at the customers site, are generally small enough that they need to be aggregated to make a sizeable impact at the transmission level, are permanent and are not under the control of the transmission owners. There are several market barriers to enlisting either private or public energy efficiency in grid planning at this time.

For private investments, the ISO would need to encourage the private sector to participate, but the private sector does not have an existing business relationship with the transmission owners or operator. Performance terms and operating conditions would need to be developed so that the ISO and PTOs would be secure that load reductions will occur when needed and the customer-owners would be secure that the cost of participation is not more than the value of the incentive they are being offered.

The State could play a role in fostering energy efficiency programs to reduce pressure on key transmission sectors. Its chief tool is the energy efficiency funded through the Public Goods Charge, which could be targeted either at generally reducing peak demand or on improving system security for end-users in transmission-deficient areas. The State could also use the Public Goods Charge money and staff expertise to foster third-party participation through program pilots, marketing, and customer outreach. Regulatory barriers would have to be overcome to target energy efficiency programs to transmission security purposes. The current program goals would need to be revised to include an emphasis on the value of reducing peak load through targeted energy efficiency investments. Achieving additional load reductions through energy efficiency is clearly feasible, but achieving them through future PGC programs will probably require the Legislature to establish this goal as a priority. Finally, the State could use its staff expertise to account for future trends in energy efficiency programs and rate design. This effort would assist the ISO and PTOs in developing load forecasts.

Distributed Generation

Technical Feasibility

For purposes of this report, distributed generation (DG) is defined as electrical generation or storage systems located at or near load centers. Such systems are typically small (less than 10 MW) and modular. They may be located at a customer s premises on either the utility or the customer side of the meter, or they may be located at other points in the distribution system, such as a utility distribution substation. They may be interconnected with the utility or serving one or more customers as stand-alone units. When located on the customer side of the meter, the DG may be sized such that the customer s load consumes all of the power generated, or the DG may generate excess power available for sale.

The potential distribution-level support services that DG may be able to provide include voltage support, reactive power, black start, congestion relief, and emergency back-up to restore power in a limited area to distribution customers while repairs are made on the distribution system. These distribution-level services affect the upstream transmission system, thereby providing support to the transmission system. Other transmission system support services such as spinning and non-spinning reserves are typically provided at transmission voltages, not at the distribution level.

DG includes technologies such as microturbines, small gas turbines, fuel cells, internal combustion engines, photovoltaics, solar dish Stirling engines, and wind. **Table 2** defines the principal types under development in California.

California currently has over 600 units installed in a size range of 100 kW to 20 MW, most of which are non-utility owned and sell power to a utility. However, not all of these units meet the definition of distributed generation presented above, in the sense that they are not all located at or near a load center. Some of these units are remotely located near wind, biomass, or hydro resources. In addition, the financial viability of many of the third-party projects has depended on favorable energy and capacity sales agreements with utilities or the sale of steam to a thermal host. Only in rare instances were these units installed for the specific purpose of providing distribution support services. As a result of these factors, California has limited experience with the installation of cost-effective DG for the purposes of providing specific grid benefits, and few instances of multiple DG units of significant size on single distribution lines. There are research efforts underway to better understand these concerns.

It may be possible to implement a DG solution faster than a traditional wires solution. Because a multiple DG unit solution can be implemented in stages, the DG solution can more closely match the actual load growth. Staging a project in smaller increments is an advantage in more slowly growing areas, because it avoids the need for lumpy wires investments. Another advantage of a multiple DG unit solution is that multiple units can provide a very high level of reliability that matches or surpasses that of the grid because it overcomes the single point failure problem of a wires solution.

A recent national distributed generation conference gathered experts to evaluate technologies, market penetration, and market barriers. Their consensus was that a new distributed generation will develop slowly at first but begin to gain force by 2004. They foresaw mainly niche applications before 2005, with an increasing market 2005 to 2008 as technology and market barriers are resolved.

Table 2
Distributed Generation Technologies

Microturbines are a relatively new technology, with sizes of 25 to 75 kW. They may be fueled by fossil fuels (e.g., natural gas, propane, distillate) or biogas. They are dispatchable, and can be used in either baseload or peaking applications. Because microturbines are new, there is a relative lack of proven performance and a lack of experience with permitting and interconnecting these systems.
Small gas turbines are well established, with sizes of 1 to 50 MW. They may be fueled by fossil fuels or biogas, are dispatchable and can be used in baseload, peaking, or cogeneration applications.
Fuel cell types include phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. They range in size from 1 kW to 200 kW. Of these types, only phosphoric acid fuel cells are available commercially, and they are relatively expensive compared to engines and turbines. Molten carbonate, solid oxide, and proton exchange membrane fuel cells are currently being demonstrated. Fuel cells can be fueled by natural gas, hydrogen, biogas, or propane. They are appropriate for baseload applications.
Internal combustion engines include diesel engines, natural gas engines, and dual-fueled engines. They range in size from 50 kW to 5 MW. They are a well-established industry and have a long history as back-up or standby generators. Like turbines, they are dispatchable and can be used in either baseload or peaking applications.
Photovoltaics (PVs), solar dish Stirling, and wind technologies are renewable, intermittent technologies. PVs range in size from 1 kW residential rooftop sizes to about 2 MW. Because a utility s peak load typically occurs during daylight hours on hot summer days, which is when PVs provide their maximum output, they are considered peaking resources; however, they are not dispatchable.
Solar dish Stirling is a relatively new technology currently being demonstrated. When operated in a hybrid solar/natural gas mode, it can be used as a dispatchable resource.
Small (600 W to 40 kW) and large (40 kW to 1.5 MW) wind units have intermittent availability, unless used with storage.
Distributed storage includes technologies such as superconducting magnetic energy storage (SMES), batteries, flywheels, and modular pumped hydro. These load management devices consume electricity during off-peak periods, but they provide on-peak power. Except for batteries, most of these technologies have limited availability and operational experience. However, they show great promise for providing grid support services such as peak shaving and local voltage support.

Implementation Issues

There are five principal issues that must be resolved for DG to compete effectively as an alternative to transmission projects identified in the ISO grid planning process. First, many of the technologies are still in the demonstration phase or the early phases of commercialization. As a result, their technical and operational performance may not be well proven. The market for each technology may develop differently over time.

Second, California lacks experience with the techniques to handle multiple DG units located on distribution feeders. Most distribution circuits in California use a radial configuration, and such circuits are designed for power flow in only one direction from source to use. DG would cause power to flow both ways. As a result, a number of design and operational issues (both normal and faulted conditions) must be addressed before it is feasible to locate DG on radial distribution feeders. Networked systems are even more complex.

Third, institutional planning barriers must be overcome. Currently, SCE and SDG&E do not consider DG potential as an alternative to traditional wires solutions in their distribution planning process. Also, with the exception of SCE to a limited degree, DG has not been considered by the UDCs as an option to provide distribution or transmission capacity relief. Utility planning engineers typically have varying levels of familiarity with different DG technologies.

Fourth, a simplified, uniform, and cost-effective interconnection process does not exist. Such a process would provide appropriate levels of public and equipment safety without harming distribution system reliability.

Fifth, many local jurisdictions lack experience with permitting the newer DG technologies, and the permitting rules vary greatly from jurisdiction to jurisdiction, particularly with respect to air quality. In addition, many of the technologies are small enough that they are beneath air quality permitting thresholds. However, there is a concern that there could be a proliferation of fossil fuel-based DG units which exacerbate the difficulties in meeting standards in districts with poor air quality.

Regulatory Activities Which May Affect Grid Planning

These issues are currently being addressed in several regulatory forums. The CPUC initiated an Order Instituting Rulemaking (R.98-12-015) in December 1998, in collaboration with the Energy Commission and the Electricity Oversight Board (EOB), to consider the impact of distributed generation deployment on California s electricity distribution systems and whether regulatory reforms to the monopoly distribution systems are needed. That process resulted in CPUC Decision 99-10-065 in October 1999, which provided a roadmap for how the CPUC, Energy Commission, EOB, and Legislature plan to address the issues surrounding deployment of DG, distribution competition, and the role of the utility distribution company in the competitive retail electricity market. A new CPUC rulemaking, R.99-10-025, was opened to deal strictly with developing specific policies and rules to remove inappropriate barriers to deploy DG in California. To that end, many of the implementation issues are being addressed in two Energy Commission proceedings, CPUC workshops, or written testimony.

The CPUC s distribution system planning and operations workshop process addresses the impacts of distributed generation on distribution system operations, maintenance, and planning. Topics being addressed are: how DG impacts the distribution system (exclusive of issues being addressed in the interconnection forum), changes in distribution system operating and planning practices that are needed to accommodate DG, how utilities can identify the level of future deployment of DG, and how forecasts of deployment can be incorporated into distribution system planning.

Over several workshops on transmission interconnection, the Energy Commission is developing simplified, uniform interconnection rules within California. Technical issues being addressed include public and employee safety such backfeed onto a de-energized circuit, unintentional islanding, need for visible disconnect switches, reliability as in preventing equipment overloads, introduction of flicker and harmonics, fault circuit contribution, maintaining acceptable voltage and power quality; and metering, monitoring, telemetry and dispatch requirements. The workshops will also identify changes to utility tariff sheets to explain the procedures for interconnecting generating units with the utility grid and methods to standardize the application and interconnection process.

The Energy Commission workshops on California Environmental Quality Act (CEQA) and permit streamlining consider the potential for some types of DG to qualify for streamlined CEQA and permit review at the local government level. DG units may be sited without being required to meet air quality standards because their size is under the permitting thresholds. As a result, the workshops are addressing potential air quality concerns and possible mitigating steps that should be taken to eliminate negative air quality impacts of siting a large number of DG units.

Other major issues being addressed via written testimony include the following: rate design and stranded costs, utility distribution company ownership and control over DG facilities, valuation of DG benefits and net metering, sale of excess capacity, and consumer education. Each of these issues impacts the overall potential for deployment. As increasing numbers and types of DG are installed and operated, valuable experience is gained, leading to an increased ability for DG to compete effectively in meeting the State s reliability needs. The CPUC decisions encompassing these topics are scheduled to be released during the first half of 2001.

As noted earlier, there is considerable uncertainty regarding the type, size, number, location, and timing of DG penetration. To gain a better perspective on these issues, the California Air Resources Board contracted with Distributed Utility Associates to estimate the economic market potential and the resulting air emissions given deployment at DG s maximum potential for the years 2002 and 2010. The draft report, released in February 2000, included only dispatchable generation facilities in the range of 50 kW to 5 MW and considered DG whose primary mode of operation was either peaking or baseload.

The report illustrates the relative ability of various DG technologies to compete in the electricity market. For example, in 2002, the report concludes that diesel engines will be the most cost-effective DG option to meet peak demand growth in the greatest number of cases, followed by the advanced turbine system, small gas turbine, natural gas engines, dual-fueled engines, conventional small gas turbines, and microturbines (see **Table 3**). By 2010, conventional small gas turbines will become the most cost-effective DG option to meet peak demand growth in most cases, followed by microturbines, diesel engines, advanced turbine systems, natural gas engines, and dual-fueled engines.[3]

Table 3
Relative Ranking of Cost-Effective DG Technologies
to Meet Peak Demand

Relative Ranking	Year 2002	Year 2010
1	Diesel engine	Small gas turbine
2	Advanced Turbine System	Microturbine
3	Nat. gas engine	Diesel engine
4	Dual-fuel engine	Advanced Turbine System
5	Small gas turbine	Nat. gas engines
6	Microturbine	Dual fuel engines

Conclusions Regarding Distributed Generation

At the present time, DG will have difficulty competing effectively to displace a transmission option, as a result of technology maturity, cost, siting and permitting, interconnection, and institutional issues and barriers. However, many of the barriers are in the process of being removed, with the goal that DG can become an effective option to meet customer, utility, or ISO needs. Thus, the further out in time the identified need for transmission upgrades is, the more likely that current barriers will be removed and that DG could compete against identified transmission upgrades. DG can be most effective as a part of a total package that includes wires upgrades as well as energy efficiency and demand-responsiveness measures. For example, where there are specific distribution feeders identified for upgrades as part of an identified transmission/distribution solution, DG could effectively compete for such portions of the identified upgrades.

Market Structure Issues

To truly understand the technical feasibility and cost-effectiveness of energy efficiency and distributed generation, we need to examine how costs and benefits could change due to potential major charges in rate design. As California moves to the end of the transition period, the CPUC is examining how customer s bills are to be constructed. If end-use rates shift from being recovered on a volumetric basis to one that combines fixed and volumetric elements, these new rates could materially affect the cost-effectiveness to consumers of their investments in energy efficiency or distributed generation.

Rate design is a crucial determinant in projecting impacts for both energy efficiency and distributed generation. This significance is true for both private response of end-users to these rates as well as for publicly-funded programs using these rates as one element of program cost-effectiveness calculations. The current rate freeze has resulted in no substantial change in rates for UDC retail customers in several years. For SDG&E customers, this rate freeze has now expired, and it is expected to do so for SCE and PG&E customers in less than two years. The flexibility of the CPUC to revise rate design for the post rate-freeze period has resulted in rate design applications by all three utility distribution companies. These applications encompass a wide range of new thinking about rate design — needed to shift into the competitive market structure created by AB 1890 — but also potentially controversial. Since it is early in the life of all of these proceedings, it is premature to predict how rate design might evolve in the post-rate freeze era; many outcomes are possible.

Rate Design Impacts on Energy Efficiency Cost-Effectiveness

Roughly one-third of an electricity bill pays for power. These hourly energy costs should flow through to end-users to facilitate an efficient energy market, but it is less clear how the remaining two-thirds of the total cost should be recovered. The remaining costs result from distribution, transmission, and customer service activities. In many respects, these are fixed costs that do not vary much with different levels of utilization. Cost causation principles suggest that these fixed costs should be recovered with fixed charges. Currently, however, these charges are almost universally recovered in volumetric energy charges. Making a change from volumetric energy charges to fixed charges would decrease the value of investing in energy efficiency.

As an illustration, suppose the following two hypothetical rate designs for a residential single family homeowner are under consideration. The Volume rate design continues to be entirely volumetric so that the energy charge fluctuates monthly to follow the Power Exchange (PX) energy price. The Fixed rate design has energy and CTC charged by volume and all remaining charges are charged on a per customer basis. All calculations assume 500 kWh in the April billing period and 1000 kWh in August. Using two months in which the amount and PX average price are different is important to understanding the full impacts of these rate design changes.

Table 4 illustrates the fluctuation in the overall bill for these three scenarios — Current , Volume and Fixed . The two columns labeled Current show the impacts for these two months of April and August of different levels of consumption. The April bill is $60 while the August bill is $120. The columns labeled Volume also show the same two months with the same two consumption levels. The rate design continues to be entirely volumetric for all components of the bill. The level of the rate is reduced by assuming that non-fossil CTC is charged at $0.005 per kWh for all months of the year. In this scenario, the April bill is $50, but the August bill is $120. Compared to the Current scenario, the April bill has been reduced, but the August bill is the same reflecting both that energy is more expensive per kWh and total energy used has doubled. Finally, the Fixed scenario illustrates a hypothetical fixed charge rate design for non-energy components of the bill. In April the bill is $57.50, which is lower than the Current bill but higher than the Volume bill. In August the bill is only $92.50, compared to $120 under both the Current scenario and Volume scenarios.

What are the consequences of either the Volume or Fixed scenarios on end-user energy efficiency cost-effectiveness? A fully volumetric rate design recovering all costs in charges that vary with energy consumption will induce energy efficiency investment compared to a rate design that has substantial customer charges that do not vary with the volume of energy consumed. In this illustration, for the Volume scenario the end of the rate freeze results in one month with total energy usage costing $0.10 per kWh and a second with $0.12 per kWh. For the Fixed scenario, average energy usage costs $0.03 per kWh in April and $0.05 per˚kWh in August. In both instances there is greater variability in the direct cost associated with energy usage, but a very large difference in the variability of the total bill between the two hypothetical rate designs.

This kind of variation in rates could have substantial impacts on energy efficiency cost-effectiveness. Compared to the flat rate of $0.12 per kWh, the Volume rate design scenario would not motivate great differences in end-user behavior than currently exists under frozen rates. Under the Fixed rate design scenario, overall there is less motivation to pursue energy efficiency of any kind since variations in the bill due to energy usage are much smaller due to the existence of fixed charges. This scenario might induce customers to pursue air conditioner efficiency improvements more vigorously and greatly lessen off-peak energy efficiency measures such as residential lighting. Over time, broad response to these new Fixed price signals would decrease summer afternoon loads and increase off-peak loads, compared to what they would have been under average rate designs.

Table 4
Illustration of Bill Impacts of Rate Design Changes

Charge	Current Rates	Current Bill	Volume Rates	Volume Bill	Fixed Rates	Fixed Bill
Units	**¢/kWh**	**$**	**¢/kWh**	**$**	**¢/kWh**	**$**
1. April (500 kWh)						
a. Energy & procurement	2.5	12.50	2.5	12.50	2.5	12.50
b. UDC stranded costs	2.5	12.50	0.5	2.50	0.5	2.50
c. T&D and other	7.0	35.00	7.0	35.00	42.50*	42.50
d. Total	12.0	60.00	10.0	50.00	N/A	57.50
2. August (1000 kWh)						
a. Energy & procurement	4.5	45.00	4.5	45.00	4.5	45.00
b. UDC stranded costs	0.5	5.00	0.5	5.00	0.5	5.00
c. T&D and other	7.0	70.00	7.5	70.00	42.50*	42.50
d. Total	12.0	120.00	12.0	120.00	N/A	92.50

* Flat charge each month, does not vary.

Rate Design Impacts on Distributed Generation Cost-Effectiveness

Rate design variations could also have large differential impacts upon distributed generation. The Volume rate design scenario would continue to have all costs recovered in volumetric charges, so an end-user contemplating DG to avoid these charges avoids all cost categories. The standby rates that might be charged would most likely reduce some of these expected savings, but large portions of UDC costs could be avoided. In the Fixed rate design scenario, much smaller portions of the monthly bill could be avoided by reducing the volume of energy purchased and delivered through the distribution system. If the fixed customer charges did not distinguish between DG facility owners and otherwise similar end-users, then the benefits of employing DG as a means to avoid UDC costs would have shrunk by two-thirds. This reduced benefit would have a very large effect on DG cost-effectiveness.

In addition to the three rate-making applications potentially resulting in major changes in rate design, the CPUC is examining distributed generation issues in the DG rulemaking R.99-10-025. A key component will be the standby rates that determine how customers normally using distributed generation to displace purchased power pay for purchased power when their DG machine is not operating. Currently, these standby rates are extremely expensive as utility costs for actual energy procurement, backup energy procurement with no notice, and transmission and distribution wires are collected in a single bundled rate. Opening testimony in the rulemaking is due on May 26, 2000.

Conclusions Regarding Market Structure

Rate design can have a profound impact on energy efficiency and distributed generation cost-effectiveness. Energy efficiency and distributed generation, whether private or funded through public programs, are intrinsically linked to rate designs that are now under consideration at the CPUC. It is not possible to predict the outcome of these proceedings, given all the discussion and debate which will take place over this summer and fall.

The CPUC s initial decisions to shift toward energy market flow-through pricing have the potential to change the traditional load patterns which are now assumed within the transmission planning process. Both energy efficiency and distributed generation affect the load pattern as they are responses end-users employ to reduce energy use and bills. Potential fundamental rate design changes may change load usage. For some transmission planning areas, changes in load patterns could change peak demand to different portions of the summer season if not out of the summer season altogether. Therefore, load forecasting methodologies need to become more sophisticated to identify when and to what extent traditional load patterns may change as a result of rate design changes. The Independent System Operator, PTOs, the utility distribution companies and the Energy Commission should work collaboratively to forecast changes in systemwide and local load patterns that would influence transmission planning results.

Section III: Grid Planning by the Independent System Operator

Section 3 discusses the Independent System Operator s grid planning process and the role played by energy efficiency and distributed generation. The planning process outlined in the ISO s initial, and still current, tariff requires that each PTO develop an annual five-year transmission plan and submit it to the ISO for review. One relevant feature of the existing tariff requires that, in considering potential solutions for grid problems, planners

> shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on generation, interruptible loads or reactive support. [Tariff 3.2.1.2]

The tariff requires that the ISO review PTO plans to determine that proposed grid projects conform to the applicable reliability criteria. Following its review, the ISO may recommend that specific studies be redone and/or recommend changes to projects included in the plan.

In a 1998 series of Transmission Planning White Papers, the ISO identified concerns with the overall process, including grid planning. These issues were addressed in a series of workshops that lasted throughout most of 1999 and resulted in proposed tariff Amendment 19 to deal with congestion problems and the proposed Amendment 24 to deal with long-term grid planning.

Perhaps most importantly, the ISO was concerned that the tariff was ambiguous concerning which entity — the ISO or the PTOs — had lead responsibility in planning the ISO-controlled grid. A second issue was that the market structure and planning process did not encourage generation projects to locate in areas where they were needed to provide local reliability support. Because of this mis-match, the ISO observed that it was relying too much on generation contracts to provide local area transmission support. Still another important planning issue was how to deal with incremental transmission congestion caused by the connection of new generation to the grid.

To date, the ISO has not focused on how EE programs, DG, and rate design could be incorporated in developing the plans for the transmission grid. The focus has been on refining transmission planning responsibilities and the criteria for approving new transmission projects. Some effort has been made on improving load forecasts for transmission plans, which would incorporate future impacts of existing EE and DG. The ISO is aware that generation or energy efficiency could substitute for some wires investments. The ISO is interested in any option that reduces the overall costs of maintaining the grid while promoting reliability through market price mechanisms. As a result, in 1999 it proposed a planning process which included soliciting alternatives as a final check on the cost-effectiveness of a transmission project.

As we will discuss in the next two sections, addressing energy efficiency and distributed generation in grid planning could be done in several ways:

- Accounting for EE/DG that is likely to occur and likely to reduce total load by developing criteria that specify the elements of load forecasts (degree of weather severity, inclusion of existing and likely program impacts, addressing rate design implications for load shape change, etc.) that the ISO would find acceptable.

- Developing estimates of existing and planned energy efficiency program impacts and the likely penetration of distributed generation as adjustments to the PTO local area load forecasts.

- Requesting the PTO or third-party sponsors to prepare EE/DG alternatives at the PTO local level as an option to defer or displace wires-based solutions.

- Examining a long-term forecast of forthcoming transmission problems and targeting EE/DG to reduce load growth in those areas.

- Developing pricing policies to foster location of EE/DG in desirable areas.

- Providing a competitive solicitation at the ISO level where energy efficiency, distribution generation, and generation could compete against transmission.

The 1999 Proposed Grid Planning Process

In December 1999 the ISO submitted a revised grid planning process, Amendment 24, for the FERC to consider. The revised planning process had two basic steps: developing an initial integrated transmission plan and conducting a solicitation to enable non-wires projects like energy efficiency and distributed generation to compete with transmission proposals included in the initial plan.

In step one, the planning process required the ISO to prepare an annual five-year integrated transmission plan for the ISO-controlled grid. The integrated plan provided an important tool by which to oversee planning results and integrate transmission planning among the three PTO service areas. The PTOs were required to prepare annual five-year transmission plans using a coordinated planning process that involves the ISO, stakeholders and other interested parties. The PTOs were required to conduct studies, identify reliability problems and service area load growth requirements and to propose solutions to those problems and needs. The PTO plans were to be submitted to the ISO for review and evaluation. Then, the ISO selected projects that conformed to ISO grid planning criteria, were cost-effective, and produced expansions and upgrades that were needed for the reliability and efficiency of the ISO-controlled grid. These were incorporated into an initial integrated transmission plan.

In step two, a solicitation was added to provide an explicit method for including non-wires alternatives on a competitive basis. In part, the solicitation process was a response to the need expressed by the ISO in its White Papers for a method to encourage new generators or other non-wires alternatives to locate in areas where they could provide reliability support for the grid when congestion pricing would not be adequate.

The solicitation process identified specific transmission projects that could potentially be replaced by non-wires alternatives. The ISO would evaluate the proposals, select winning bids, prepare a Final Integrated Plan and obtain ISO Board approval. The final plan would include projects chosen through the competitive solicitation processes as well as projects selected by standard planning procedures.

Concerns About Long-Term Grid Planning

On February 4, 2000, the ISO withdrew Amendment 24 from the FERC. This action was taken as a result of several considerations. The FERC had recently rejected two ISO proposals related to grid planning, Amendment 19 dealing with its proposed Intrazonal Congestion Management approach and Amendment 23 concerning the use of reliability must-run facilities for managing intra-zonal congestion. As the ISO stated in its withdrawal letter:

> The ISO believes that the issues involved in the reexamination of congestion management may be related to some of the issues raised by intervenors with respect to the competitive solicitation process proposed by Amendment No. 24. The ISO believes that until these related issues are fully discussed and examined, it is premature to proceed with the long-term grid planning process.

In addition to the two recent FERC rejections, the ISO was faced with numerous intervenor objections concerning Amendment 24. Stakeholders identified the following major implementation concerns: market design issues, cost recovery, and comparable reliability and feasibility. Many commenters, even those supportive of a solicitation option, were concerned about the feasibility of and the ISO s authority over non-wires projects if those projects were built in lieu of transmission upgrades. All argued that the implementation details were sufficiently important that they had to be worked out before tariff language could be approved.

Market Design Issues

The stakeholders principal concern was that market design issues had to be fixed before a sensible grid planning process could be developed. Parties believed that reworking congestion pricing would largely solve the locational difficulties that were distorting generation and transmission development. Many believed that effective transmission planning could not take place until the congestion pricing structure provided locational signals. Once congestion management was solved, grid planning would be dealing with a much smaller problem than the one it was attempting to resolve. The belief was that, as expressed in FERC s Regional Transmission Organization Final Rule, the planning role may be largely limited to extreme circumstances where continuing congestion in an area threatens reliability [FERC mimeo at 488].

For example, Sempra argued that the existing market design, coupled with the current congestion management approach, fails to create adequate price signals to provide incentives to new generation or other non wires alternatives to solve grid reliability problems. The result is an administrative band-aid approach to solving grid problems. The Northern California Power Authority was also concerned about the effectiveness of congestion pricing signals for encouraging locational siting of generation or for developing economic transmission projects.. Sacramento Municipal Utility District (SMUD) stated that: Permitting the ISO to engage in market-driven long-term grid planning and expansion before it gets its short-term congestion management house in order is putting the cart before the horse [SMUD Motion to Intervene and Protest, Jan. 20, 2000, mimeo at 6 and 7]. .

Alternatives to Transmission Upgrades

Opinions ranged widely on whether consideration of non-wires alternatives ought to be within the ISO s purview. At one end of the spectrum, Edison stated that the job of the ISO is only ensuring a robust, reliable transmission grid that can support an unencumbered generation market. They went on to assert that the grid planning process pits the transmission wires business against an unregulated generation business in an effort to maintain the reliability of the transmission system. The likely result of the ISO s process is more and more non-wires contracts that will undermine effective competition and further mask appropriate price signals.

Many stakeholders were concerned that the ISO s proposed solicitation process was an extra market method of subsidizing third party non-wires projects, not a market approach. The process offered special incentives to encourage non-wires facilities to locate in particular areas which would provide that generator with local market power compared to generators located further away (see discussion of the Tri-Valley RFP).

A third group--including the CPUC, SMUD, Redding, and Santa Clara--saw a role for non-wires projects as long as congestion management was addressed first. Effective congestion management would limit the potential need for ISO contracts for non-wires options.

At the other end, the Independent Energy Producers, Reliant and the City and County of San Francisco all saw value in non-wires alternatives to enhance system reliability. They tended to be concerned about ISO and PTO implementation restrictions and whether alternatives should play an even stronger role than the ISO envisioned.

Cost Recovery

Cost recovery, whether payments are aligned with the costs and benefits incurred by various parties, is at the heart of many concerns. Cost recovery for third-party projects would allow successful bidders to recover part of their costs from a contract with the ISO. The ISO in turn would recover costs through the PTO s transmission rates. Some stakeholders, such as California Department of Water Resources, believed that spreading the costs to all users of the grid would be unfair. Costs would not be assigned to the direct beneficiaries of the non-wires project. From a different point of view, the CPUC was concerned that retail, end-use customers would pay a disproportionate share of the costs recovered through transmission rates. They believed that costs should be apportioned among all wholesale and retail transmission customers of the relevant PTO.

A related concern addressed by PTOs is that the cost recovery mechanism shifts the risk for funding third-party projects from developers to the PTOs. The PTOs were concerned that they would bear the burden and risk of funding non-wires projects. And, the FERC has not yet indicated it would authorize funding non-wires projects through transmission rates. Although not stated, the PTOs are probably concerned that successful projects chosen through the solicitation process would displace transmission projects in the PTO rate base, thus reducing the potential returns to their shareholders.

The cost recovery mechanism for non-wires projects raised concerns of a different sort for independent developers. While generally agreeing with the solicitation process, independents such as Independent Energy Producers expressed concern that the PTOs could hold non-wires projects hostage by delaying the applications for rate recovery .

A way to side-step the contractual issues would be for DG projects to be owned or controlled and operated by the Participating Transmission Owner specifically for local transmission support. (This option would not work for EE options, which is built into the customer s property and is usually a permanent reduction in consumption.) If this DG existed solely to support the local transmission system, operated for limited periods and was a price-taker in the market, it could probably be justified for rate-recovery. However, stakeholders might be concerned that the DG not take potential energy sales out of the market as a by-product of supporting the local grid and that the PTO not own enough DG to obtain local market power.

Comparable Reliability and Feasibility

A final group of concerns stated that non-wires projects were not complete substitutes for transmission upgrades because they did not possess the same security attributes such as voltage support and stability. Stakeholders felt that many implementation details needed to be resolved before comparable reliability could be assured. For example, there was a potential conflict of interest for the PTO conducting planning studies on alternatives that would displace their transmission project. Other problems were that the criteria for choosing among projects were not specified and it wasn t clear who would be liable if the non-wires project did not perform. Parties also were concerned that the potential interaction between these contracts and either reliability must-run contracts or flexibility of participating in the energy markets had not been sufficiently addressed. Opinions of stakeholders varied regarding whether satisfactory details could be developed.

March 2000 Revised Grid Planning Proposal

As an interim approach, the ISO has proposed resolving two problems in the near-term via a narrowly focused tariff amendment with a streamlined set of rules. The proposed rules would make the ISO ultimately responsible for planning and expanding the ISO-controlled grid. This plan would be based on consistent standards, so that comparable reliability is obtained across the grid. The proposed rules do not, however, address non-wires alternatives such as EE programs or DG investments.

The ISO hopes to file this narrowly focused tariff in June. To address congestion problems, the ISO is conducting a systematic review of congestion management and, after that is resolved, intends to reconsider non-wires alternatives this autumn.

An Initial Assessment of Alternatives in Grid Planning

The past two years of developing the ISO s process for grid planning have identified four key issues for evaluating how EE/DG options might be incorporated. They are:

- accountability for accurate load forecasts,
- the appropriateness of a market design which provides non-market incentives,
- the suitability of recovering costs for non-wires projects in transmission rates, and
- the feasibility and mechanics of incorporating non-wires projects into the grid.

The load forecasting and market design issues are in the process of being resolved. The most significant policy issue has been whether to support funding non-wires alternatives found beneficial to the grid. Whether to allow non-wires alternatives goes to the heart of the function of the ISO and its role in a restructured electricity market. Is the ISO charged with providing a reliable grid at least cost, recognizing that transmission, generation and load reductions can, in some circumstances, be substitutes? Or, are they charged with providing a least cost transmission system that serves an unregulated energy market? The principal focus of this debate has been on generation; energy efficiency and distributed generation investments are relatively minor elements.

Energy efficiency and distributed generation can dampen load growth and subsequent demands upon the bulk transmission system. This suggests that the ISO should have the option of obtaining cost-effective EE/DG to maintain a least-cost system.

On the other hand, the tensions between the merchant function and the regulated world make managing these alternatives administratively complex and perhaps even infeasible. In a hybrid market, there is a strong incentive for market-based products to lean on the regulatory cost-recovery. If they are successful, then they have a competitive advantage. In such a case, the total costs of the solution may be higher than those upon which the cost-effectiveness assessment was based. In addition, a host of unresolved administrative issues regarding liability, non-performance, control, cost-recovery, and market freedom were unanswered in Amendment 24 and the Tri-Valley RFP. In solving the transmission reliability problem, we might be creating a market problem by enhancing the competitiveness of one alternative.

Currently, the ISO and stakeholders are re-evaluating whether non-wires options should be considered in transmission planning at all. Much work remains to be done on whether a market-based solution can be identified. When that is resolved, the potential application to distributed generation and energy efficiency should be revisited.

Case Studies — Pilots in Progress

In addition to developing tariff language in 1999, the ISO also initiated two pilot projects — the San Francisco Peninsula Study and the Tri-Valley RFP. Although not designed specifically as a field test of grid planning that would include alternatives, the San Francisco Peninsula Study illustrates the difficulties of addressing EE and DG in grid planning. The Tri-Valley RFP was a pilot project.

The San Francisco Long-Term Reliability Study

This project is an attempt to develop an integrated grid plan which includes EE or DG options. To date, treatment of EE and DG as options for reliability has been fragmented and not produced real options comparable to the transmission upgrade options.

When compared to other major cities in the United States, the San Francisco Peninsula has a rather unique electrical grid. Only one transmission corridor brings essential imported power to the residents, while two old power plants within the City and County of San Francisco (CCSF) meet the remainder of the demand. The local load is increasing, as is the load in the greater San Francisco Bay Area, so reliability concerns were already on the horizon, even before the December 1998 power outage. It affected over one million people and lasted just over seven hours, causing financial, health and safety impacts of between $200 million and $400˚million. In the wake of the outage, the ISO conducted a disturbance study which recommended that CCSF join with PG&E, market participants, and the ISO to develop a long-term reliability plan for the San Francisco peninsula. The ISO announced the study in May 1999. All interested parties were encouraged to participate.

The study group met for the first time in June of 1999. Led by the ISO, the study group includes the transmission owner, numerous generation developers, four state agencies, several power marketers, three local agencies, citizens representatives and public interest groups. The group agreed:

> In this forum, all options will be explored, including transmission upgrades, siting new in-area generation, upgrading the existing in-area generation and load management. The document serves as the blue print to the technical study that will assess the existing reliability of the San Francisco Area, explore the adequacy of the system in the future, and evaluate alternatives to maintaining or improving San Francisco reliability.4

Because of extensive public interest participation in the study team, the potential impact of EE or DG was included as a sensitivity analysis in developing the load forecast. Since there were not any defined programs or projects to be modeled, a sensitivity case of ten percent decrease in the annual load is being used to estimate the effect of EE programs, while some portion of a generic block of 400 MW additional generation would represent DG resources.

Energy Efficiency/Distributed Generation Alternatives

The principal problem facing the group was the lack of a third-party project sponsor who could bring real projects to the planning process. One EE aspect the group hoped to explore in the study was the potential for moving some energy intensive commercial and industrial load from peak to off-peak, thereby reducing the need for on-peak capacity. The Energy Commission staff drafted a plan to look at the potential for load shifting in the City, but was unable to obtain resources to conduct the study. PG&E reported that it did not have any special San Francisco programs, but that large industrial customers could volunteer for a load management rate which gave them lower rates in exchange for the possibility of being curtailed in periods of peak demand.

The CCSF expressed great interest in considering EE/DG options for dealing with grid reliability on the Peninsula and asked whether any State programs could be accessed to help solve the reliability problem. The City has looked at the possibility of utilizing existing back-up generators in city/county buildings as peaking resources, but learned that most of these diesel units are only designed to run long enough to evacuate the respective buildings. The Energy Commission does not have current program funding or program analyses that spelled out how to tailor EE programs to reliability concerns. PG&E and the CPUC do have authority to administer Public Purpose Energy Efficiency Funds through the year 2001. Theoretically, these funds could be used to address the specific issue of reliability in San Francisco, but there were policy barriers to focusing funds collected from all ratepayers on a limited geographic area.

The California Alliance for Distributed Energy Resources and representatives of two companies spoke to the study group about DG demonstration projects, but no proposal was put forward identifying capacity of DG generation to be provided.

Interim Conclusions Drawn from San Francisco Pilot

The ISO and PTO have not considered EE and DG options of primary importance. They are focused on transmission and distribution. No advocate has been effective in bringing EE and DG projects to the forefront. The key process issues which have emerged from this pilot are that:

- a wide spectrum of parties are willing to consider EE, DG and generation as alternatives to transmission in the planning process;
- the ISO and PTO consider themselves as responsible for defining transmission alternatives;
- the ISO and PTO are relying on voluntary project sponsors, either governmental or independent, to bring EE/DG projects to the plan;
- no government agency has the responsibility to proffer EE or DG alternatives to a local project;
- unlike transmission, there is no match between EE/DG advocacy and project funding; and
- a process has not been developed to effectively engage independent EE/DG developers in local transmission planning studies.

The Solicitation for Tri-Valley Area Transmission Alternatives

In September 1999, PG&E s grid planning process issued a transmission study report concluding that over the next 15 years the Tri-Valley (the cities of San Ramon, Dublin, Pleasanton, Livermore, and portions of Alameda and Contra Costa counties) peak loads are forecast to double and raise total demand from today s 450 MW to about 940 MW. The electric distribution systems and substations in that area will soon be loaded to 100 percent of their distribution load carrying capacity. PG&E defined transmission projects they recommended to meet this peak load need.

The Solicitation for Alternatives

On January 18, 2000, the ISO released a solicitation inviting bids to determine whether or not peaking generation and/or peak load management projects could be viable alternatives to PG&E s proposal for a $39 million transmission project in the Southern Tri-Valley area. This RFP for transmission expansion alternatives is the first to be released by the ISO. However, conditions and requirements contained in the RFP and ISO explanations provided at the February 7, 2000 pre-bidders conference appear to substantially limit the type of EE or DG projects that could meet the terms of the RFP.

In designing the RFP, the ISO staff developed conditions that, if met, would meet the requirement of comparable reliability to a transmission solution to a load growth problem, while not impacting the overall energy market. The conditions included: five-year contract for a locational incentive only, need to be operational by April, 2001 (and hence a short RFP response time), location, hours of availability, and telemetry.

Five-Year Contract and Payment Terms: The contracts would be for a maximum of five years from April˚2001 until October 2005. The term limit is designed so that responses to the RFP will be evaluated as deferring, not displacing, the proposed Tri-Valley transmission project. The ISO believed that non-wires projects should be built based on the expectation that these projects will generate revenues from the market sufficient to cover the cost of the projects. The only payment that the ISO was willing to make to any successful RFP respondent would be an incentive payment for location, to compensate for the cost premium of locating the project where the ISO needs it. An EE or DG alternative would have to recover its costs from energy savings. It is unclear how to calculate a locational incentive for such technologies that, because customer based, are instantly location-specific.

Timeliness and Location: To provide benefits similar to the Tri-Valley transmission upgrade, the project(s) must be up and operating by April 2001. EE and load management could be operational by then. But, to give generation a reasonable chance of being built by 2001, the RFP was issued with only a six-week response time so awards could be made quickly. (This deadline was later extended two additional weeks.) Six or eight weeks was not sufficient time for most potential DG/EE respondents to conduct a feasibility study and market analysis to determine whether they could develop a cost-effective project. Projects had to be located in the Tri-Valley area. Only those individuals with a prior working knowledge and familiarity with the Tri-Valley area had a chance of producing a credible response to the RFP.

Hours Needed: The project must be available for the ISO to call on during summer peak hours. To verify operation, EE projects would need potentially expensive, new demand meters. Currently, most EE projects that reduce peak load, such as high efficiency lighting retrofits and high efficiency air conditioning, are on rate schedules which reward total energy savings rather than savings on peak. It is not apparent what the RFP offers that would attract EE projects. Load management projects focusing on load shedding would be compatible with the limited hours as specified in this RFP. Facilities with load shedding capability already have the option to participate in UDC interruptible rate programs, and it is unclear whether an incremental payment would be more attractive than the existing rate option.

Operating Requirements: All projects are required to enter into Participating Load or Generator Agreements**.** The projects must comply with metering, telemetry, and dispatching requirements established in participating load/generation agreements. The participating generator agreement may be a barrier for small generators. The participating load agreement is new and may be a barrier to potential load management projects. EE projects cannot meet the terms of the participating load agreement. The projects will incur costs associated with purchasing, operating, and maintaining the metering, telemetry, and dispatching equipment required by the ISO. The magnitude of the costs for this equipment is unknown but could adversely impact the economic feasibility of potential projects. Energy efficiency projects are not compatible with the metering, telemetry, and dispatching equipment requirements.

Conclusions from the Tri-Valley Solicitation

At the time of this report (April 26), the ISO management had just announced the results of the Tri-Valley RFP and presented two policy questions to its Board of Governors. Four projects totaling 220 MW of generation and 5 MW of load management through DG applied. ISO management determined that to displace or defer the transmission upgrade, all four projects would be necessary and that the total cost of alternatives was substantially higher than the cost of building transmission. ISO management recommended that the transmission project be built rather than the alternatives. They also asked the Board to consider:

- whether the ISO should provide for direct competition between transmission, generation and load-based projects, and
- whether the ISO should evaluate alternatives based on the possibility of deferring transmission or displacing transmission altogether.

These questions are two of the key issues which this report had identified as fundamental to resolving the future role of alternatives in the long-term grid planning process.

While the Tri-Valley RFP allowed EE and DG alternatives, it was written in such a way that only generation and, to some extent, load responsiveness could respond. It was the ISO s first attempt, and the rapid development did not allow the solicitation to be designed with distributed sources in mind. Therefore, it is not surprising that the implementation details did not accommodate investments in EE or DG projects.

For an RFP to attract energy efficiency or distributed generation alternatives, tailored implementation rules are necessary. The ISO s approach of relying on market participants to come forward and champion their solutions depends on having market participants. Unlike generation, there is not a pool of EE/DG developers who are experienced in working with the transmission operator and can afford the risks of competing in a solicitation. Further developmental work is necessary to take the RFP concept from prototype to commercial implementation.

Section IV: Options for Integrating Energy Efficiency and Distributed Generation into Grid Planning

This report studied four principal options for the Independent System Operator to integrate EE and DG into the grid planning process:

- **Option 1**: Develop an improved load forecasting process that would incorporate the potential impacts of energy efficiency and distributed generation as part of the current grid planning process. This option could be accomplished by developing a list of criteria that specify the necessary elements of load forecasts or by providing forecast inputs directly to the transmission planners.

- **Option 2**: Require sponsored investments in energy efficiency and distributed generation to be evaluated as options to defer or displace upgrades to the transmission system.

- **Option 3**: Conduct five- to ten-year assessments that would identify emerging transmission problems and focus investments in energy efficiency or distributed generation there, possibly by requesting that the State redirect Public Goods Charge investments to reduce peak demand in specific areas.

- **Option 4**: Provide a competitive solicitation at the Independent System Operator level in which generation, energy efficiency or distribution generation could compete to provide reliability benefits equivalent to the expected benefits from one or a number of proposed transmission projects.

We evaluated these four options in light of the technical feasibility and market design issues discussed in previous sections.

Option 1: Future Impacts in Load Forecasts

The first option is to include the impacts of future energy efficiency and distributed generation within the load forecasts used for transmission planning. This option will result in improved planning efficiency for transmission upgrades, because it will assure the amount of transmission upgrades required is not overestimated. When added to an improved estimate of the sensitivity of loads to higher temperatures, the total impact would result in improved planning efficiency. Compared to the size of transmission projects, this option is low cost, feasible, cost-effective and free from problems about whether costs could be recovered in regulated rates.

Because much of the EE and DG activity will take place as private end-users respond to basic energy prices by installing EE measures and DG in their premises, and such impacts on loads have to be taken into account in load forecasts, the real question is whether standards and programmatic EE impacts should also be taken into account through load forecasts. At this time, these impacts are not readily translatable into the transmission planning regions that the PTOs use for their planning studies, which explains why both price-responsive and programmatic EE impacts are not now being taken into account in PTO load forecasts.

Including energy efficiency impacts is a technical work activity that should be accomplished as quickly as feasible. Absent their inclusion, load forecasts used to justify transmission expansion are systematically high. Because existing expertise on forecasting energy efficiency impacts and forecast design resides at the Energy Commission, the State could assist the ISO and PTOs in two ways. One would be to propose standards and methodologies which the ISO should require for all load forecasts. For example, regional-scale load forecasting methodologies could be required. At least two approaches may be feasible. End-use load forecasting techniques could be applied at the scale of the 150 or so transmission planning areas. Alternatively, PTOs could continue to use of their load forecasting techniques, but with adjustments from external computations of impacts, perhaps using techniques that allocate broad regional impacts into the smaller geographic areas used for transmission planning. A second possible State role would be to participate directly in the forecasting process and provide energy efficiency estimates directly to the transmission planners.

The situation for including the impacts of DG in load forecasts is more complex. At first glance, one could propose that the DG impacts should parallel the proposed treatment of EE impacts discussed above. In the parallel approach, DG and an equal amount of local load would be netted out from the load that is served by transmission wires. The DG would be invisible to transmission planners. However, because DG facilities are really generators and their effect on transmission security is important, forecasts must account for both gross load and gross generation. Netting load and DG energy are inappropriate planning techniques, at least for the larger DG facilities that might justify displacing transmission facilities. These facilities affect both elements of reliability — adequacy and security. In the post-2004 period, the potential widespread DG penetration will necessitate creating a more complex transmission planning methodology that keeps track of loads, DG capacity, likely operating behavior, and transmission capacity, so that assessing transmission system performance can be examined in the context of all factors.

The ISO and PTOs have encouraged all stakeholders to assist in improving the load forecasts. To date, the Energy Commission staff has been able to comment on overall levels but has not had the locational detail necessary to translate its analytic database to the disaggregated size required by transmission planning. In general, the quality of end-use peak forecasting has lagged behind end-use consumption forecasting. The Energy Commission has invested research dollars in strengthened peak forecasting and proposes to work cooperatively with the ISO, PTO s and market participants.

At a minimum, these criteria should address the following areas:

- The severity of weather assumptions for temperature sensitive loads.
- The effects of the Public Utilities Commission s rate design decisions on load patterns and investment incentives.
- The forecasted effects of market-responsive and program-based energy efficiency programs.
- The forecasted penetration of distributed generation as an end-user bill reduction technique and as a distribution system reliability measure.

Option 2: Sponsored Energy Efficiency/Distributed Generation Projects in Transmission Owner Plans

When a PTO is examining options to address a local load growth or system security problem, it has literally dozens of different combinations of equipment that could work. At this level, it is much more realistic to consider a smaller, local alternative such as energy efficiency or distributed generation. Energy efficiency or distributed generation could be included as a component of a larger group of projects which, taken as a whole, resolve the problem. By the time a transmission project has been selected and sent to the ISO for approval, it has such a unique constellation of attributes that few energy efficiency or distributed generation options can provide equal benefits.

This option is not pursued today because the PTO is responsible for transmission options only. The CPUC may decide in its current rulemaking whether UDCs can be owners of distributed generation facilities. If it does, this may expand the PTO/UDC repertoire of options. As has been demonstrated in the San Francisco Peninsula study, the ISO and PTO were open to a third-party sponsor bringing an energy efficiency or distributed generation project to the table, but there are no incentives and plenty of risk in such a third-party proposal. It is not yet resolved what the contractual and operational practices would be, whether an incentive payment would be authorized, who would be responsible for the project s performance, and how much risk an EE/DG developer would be expected to absorb in the process.

This option might deliver a more cost-effective solution to the ISO, but it needs to be tested in a focused demonstration. The ISO or its designee would need to commit resources to run the demonstration, market the opportunity to potential developers, work with parties to design model RFPs and contracts, and test the feasibility of a program design. If the legislature were to authorize it, state regulatory agencies could participate with the ISO to oversee this project and could provide partial funding.

Option 3: Energy Efficiency Investments

This option draws on the State s experience with effectively implementing energy efficiency programs. To be successful, programs may take a year or two to get started and need to run for several years to gain sufficient customer participation. Transmission planning is focused on the next five years, and principally on the next two. In this option, an additional five- to ten-year outlook would be needed to identify emerging peak demand problems that might result in transmission upgrades. This information would be distributed to market participants and fed into program planning for Public Goods Charge expenditures. The information would be disseminated about where the most cost-beneficial efficiency investments would be, including the potential to reduce costs to California s transmission ratepayers. The programs could be targeted to those locations.

This option benefits from using the known features of successful energy efficiency program. EE programs would not have to be quickly cobbled together to compete against the specific security and adequacy attributes of an identified transmission project. Further, public EE investments would be located in areas where the system benefits accrue to all ratepayers. It might also provide an early alert system to transmission planners on how rate design is changing the market fundamentals of peak demand. Building a transmission system based on an historic peak load profile and very hot weather is going to become increasingly risky if demand responsiveness takes off and consumers alter their purchasing behavior.

This option does not address distributed generation because there is no public program directing where DG shall be built. However, the implications of future DG development could be fed into the five- to ten-year outlook.

This option would require cooperation among State agencies, the ISO, PTOs and market participants. The Energy Commission would need to participate with the ISO/PTO load forecasting process. The Public Utilities Commission would need to approve targeting of programs, and should consider whether increased program flexibility or multi-year funding would be beneficial. The ISO and PTOs would need to produce longer-term forecasts than they now do.

Option 4: Alternatives to Identified Transmission Projects

This option provides a competitive solicitation for non-wires alternatives to specific transmission projects. Once the PTOs had conducted their transmission planning process, the ISO would identify projects which are subject to a competitive solicitation to identify any cost-effective alternatives.

This alternative is part of the larger debate about whether non-wires alternatives should be funded at all, and if so, whether non-wires alternatives should be limited to security transmission projects. Some parties are completely opposed to allowing non-wires alternatives to transmission, because they believe that transmission should be a super highway which facilitates power coming from many locations to competitively supply a local need. If that debate is resolved in favor of allowing non-wires investments, the ability of EE programs and DG facilities to compete on economic terms with identified transmission projects is still doubtful at the current time.

Energy efficiency measures are necessarily diffuse and involve numerous participants. Packaging measures into a program could provide the appropriate scale of impacts to compete with a transmission project, but such packaging could hardly be accomplished in the limited timeframe that the ISO had proposed in its Phase 2 solicitation. To succeed, a program designer and proponent would have had to previously identify how a program could compete with a likely transmission project, and then lie in wait for the opportunity to contest for the opportunity to substitute for a specific transmission upgrade. This seems unrealistic.

DG facilities are expected to be larger and, therefore, fewer of them might be needed to be equivalent in capacity to the identified transmission project. Although DG alternatives would be easier to organize, DG facilities are usually built as cost-saving mechanisms to reduce overall energy expenditures or to achieve greater reliability than is generally available from grid-provided electric service. Part of these savings stem from operating the DG facility on a schedule that maximizes the economic benefits to the project sponsor — usually the occupant of a commercial or industrial premise. An operating schedule and set of commitments that provide equivalent attributes to a transmission project may disrupt the operating schedule most beneficial to the premise occupant. Because energy costs are typically a small portion of most businesses total cost and the costs of disrupted service are high, most firms are not likely to tolerate disruptions in premise schedules.

A final concern is that the ISO is separately in the process of developing and imposing new metering and telemetry requirements for all generators. The ISO wants to ensure that it has a firm knowledge of operating and emergency reserves in the new paradigm of WSCC fines for reliability criteria violations. Some metering and telemetry requirements are likely to be imposed by the ISO on any projects successfully displacing a transmission project to ensure that the DG facility was actually operating according to the schedule and operating conditions needed to satisfy the original transmission project requirements. This requirement would impose additional costs on a DG facility, both in terms of initial costs as well as in ongoing operating costs.

These considerations make EE and DG unlikely to be successful in displacing transmission projects once the transmission has been identified and specific needs characterized. At this time, we find it unlikely that EE or DG could be successful in a competitive solicitation. However, should the ISO implement a competitive solicitation, the solicitation should be designed to include EE and DG options. For a local situation, they might be a cost-effective choice, and the contractual issues should be no more difficult than those for a generator.

Recommendations

We recommend that Option 1, improving the load forecasts, be pursued. The ISO and energy agencies should use a stakeholder process to develop explicit criteria for PTO transmission planning area load forecasts. The PTOs, the utility distribution companies, the ISO and the Energy Commission should work collaboratively to forecast changes in systemwide and local load patterns that would influence transmission planning results.

We believe that Option 2 has merit and should be considered as a demonstration project. It might be prudent to wait until the 2002 annual planning cycle to test this concept, when the distributed generation market barriers have been addressed, post-transition rate design has been addressed, and the future of the Public Goods Charge for energy efficiency has been established. A commitment now to developing the demonstration would allow adequate time to prepare the background material, work out an effective commercialization plan, and identify the accountable parties.

We also believe that Option 3 is worthy of further exploration with the Legislature, energy agencies, and stakeholders. However, Option 4 appears to have little likelihood of success.

Although it has proven difficult to design a method for energy efficiency and distributed generation to participate directly in grid planning, these alternative investments can contribute to system adequacy and grid reliability. The difficulties arise in designing focused EE or DG investments to defer or displace specific transmission projects. Over the years, the Energy Commission has faced a similar problem in how to compare energy efficiency to proposed power plants. As the Warren-Alquist Act codified, it is unreasonable to expect that a group of programs could be suddenly designed and sponsored to replace a power plant. Similarly for transmission, the principal role of energy efficiency and privately-owned distributed generation appears to be reducing total load growth before transmission options are evaluated.

Endnotes

1. FERC s Rule 2000 states: the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities.

2. The peak demand impact is an estimate made by applying typical load shapes to the GWh savings reported by utilities. The utilities are not required to measure or report peak savings. The 192 MW estimate includes the peak saving impacts of previous contractual commitment form 1996 and 1997 programs and the impacts from 1999 program activities. The 192 MW number may overstate the actual peak impacts from efficiency investments in the summer of 2000 because anywhere from 33 to 50 percent of these 1999 program projects were signed in calendar year 1999 but installation may not be completed until late 2000 or 2001 for some new construction projects.

3. It should be noted that this macro-level study of DG penetration levels is of limited value in determining the ability of DG to compete in specific locations.

4. San Francisco/Peninsula Technical Study Plan July 31, 1999, Final Draft, Version 3.0.0., page 2. Authors are Ron Daschmans at the CAISO and Stan Nishioka, Transmission Planning, PG&E.

5. Although utilities typically report expenditures and impacts as occurring in the year in which funds were committed, some recent DSM programs committed expenditures of funds approved before 1998 into post-restructuring years (i.e., 1998). In 1999, the utilities reported expenditures and impacts of pre-1998 programs that occurred during calendar year 1998. For this analysis pre-1998 impacts and expenditures are not considered part of 1998 programs.

Appendix A: DSM Program Impacts

To estimate savings from future efficiency programs the Commission used the DSM Energy Resource Assessment Methodology, a program-based method that is an extension of methods used to derive Commission committed DSM forecasts. It uses assumptions about program funding levels, energy savings per dollar spent, program impact decay over time, and program lifetimes to derive both the first-year and annual program savings. Lifecycle energy savings are estimated using first year savings and assumptions about the useful life of the energy technologies or measures promoted by each program, drawing upon previous utility and Commission program-level determinations of energy efficiency impacts.

Over the past ten years, energy saved per program dollars spent has decreased slightly; estimates of remaining cost-effective energy efficiency potential are based on the assumption that this trend will continue indefinitely. However, the decline in electricity savings per dollar invested in energy efficiency programs has not been the same for all programs in all sectors for all utilities. Indeed, some sector programs have even seen increases in energy savings per dollar. It is possible that the observed declines in efficiency gains are the result of correctable program design problems, within-utility funding reallocations, or reasons not yet identified.

Savings are derived from utility estimates of first year energy savings achieved by programs as reported to the CPUC annually. The impacts used in the analysis include effects from energy efficiency and new construction programs, but exclude energy savings from load management programs (such as thermal energy storage and air conditioning cycling), because energy savings is only a small component of those programs. Excluded also are savings from residential low income assistance programs, fuel substitution programs, and load retention and load building programs. Also, utilities do not report savings for information programs.

To assess the peak demand impacts of electricity efficiency programs, three different scenarios of funding levels were evaluated for the years 2002 through 2015:

1) *No More Funding* after 2001— assumes that program funding will be continued at 1998 levels through 2001.[5] Programs will be terminated after 2001, although the effects from these programs are assumed to persist beyond 2001 reflecting the endurance of each program s impacts.

2) *1998 Funding* level— assumes that funding is maintained at 1998 levels through 2015.

3) *High Water Funding* — assumes funding is restored to the highest level since detailed reporting on IOU program funding began in 1988. In real terms, this peak was approximately 43 percent greater than the 1998 level.

Figure A-1 shows estimated peak impacts of IOU Public Goods Charge programs at alternative funding levels beginning in 2002. Under *No More Funding after 2001*, savings would continue after 2001 when funds are terminated, but taper off eventually to about 600˚MW as the residual benefits of past program expenditures diminish. Maintaining utility energy efficiency programs at recent levels (the *1998 Funding level*) would more than triple peak reductions by 2015 compared to the first scenario. If funding were increased to historical highs, the *High Water Funding* scenario suggests that energy efficiency programs would reduce peak demand by further increment of about 500 MW.

Figure A-1
Historic and Projected Peak Savings from Utility Energy Efficiency Programs
(MW)

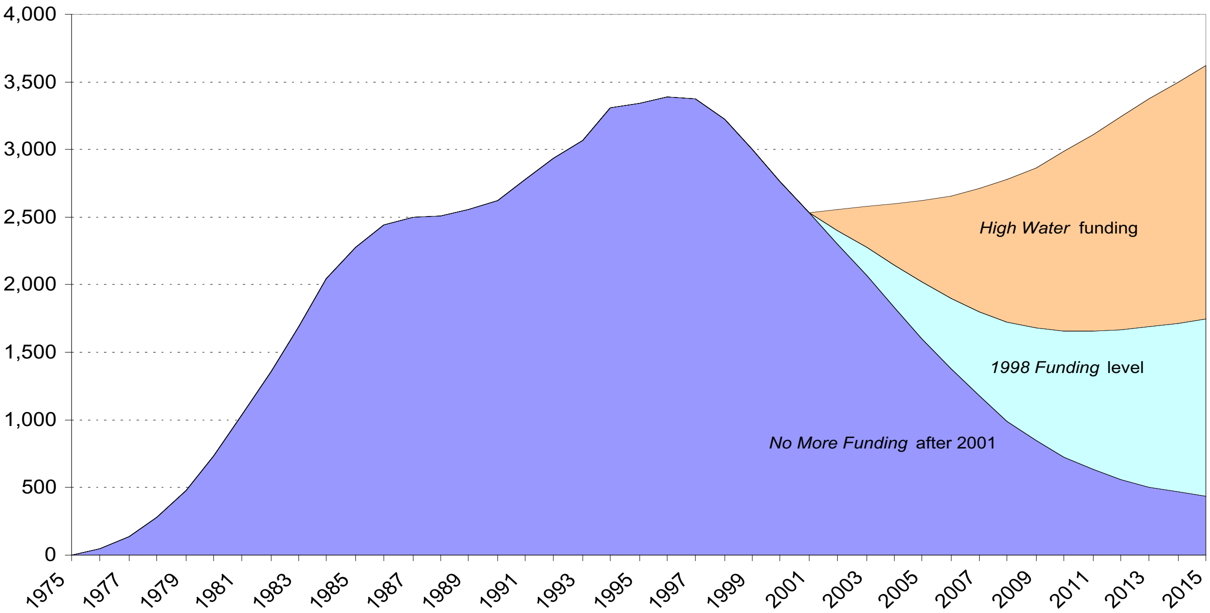


Table A-1 provides annual energy and peak demand impacts of PGC-funded programs for each of the major utility service areas. These annual DSM program impacts are consistent with **Figure A-1** and **Figure 3** in the main body of the report. **Table A-1** indicates the annual energy and peak demand impacts that the Commission estimates would result from continuing the 1998 level of expenditures on PGC-funded programs. These are the Energy Commission s best current estimates of the impacts of PGC-funded programs for the period 1998 — 2002. These impacts should be further allocated and included within the load forecasts used by the three PTOs in the ISO year 2000 transmission planning activities, as should impacts from any future changes to building and appliance standards.

Table A-1
Annual Peak Demand Impacts from Public Goods Charge-Funded Programs (MW)

PTO Service Area Impacts	1998	1999	2000	2001	2002
PG&E					
Prior programs	1023	971	913	847	773
1998-2002	86	173	259	345	392
SCE					
Prior programs	1627	1471	1320	1179	1049
1998-2002	86	172	257	343	407
SDG&E					
Prior programs	279	272	262	250	235
1998-2002	20	40	61	81	101